Western Area Power Administration
Rocky Mountain Region

Loveland Area Projects
Customer Brochure

Proposed Rates for Transmission and Ancillary Services

June 2003

Contact Information

Mr. Joel K. Bladow
Regional Manager
Rocky Mountain Region
Western Area Power Administration
5555 East Crossroads Boulevard
Loveland, CO 80538-8986
Telephone: (970) 461-7201
e-mail: bladow@wapa.gov

Mr. Edward F. Hulls
Operations Manager
Rocky Mountain Region
Western Area Power Administration
5555 East Crossroads Boulevard
Loveland, CO 80538-8986
Telephone: (970) 461-7566
e-mail: hulls@wapa.gov

Mr. Daniel T. Payton
Rates Manager
Rocky Mountain Region
Western Area Power Administration
5555 East Crossroads Boulevard
Loveland, CO 80538-8986
Telephone: (970) 461-7442
e-mail: dpayton@wapa.gov

Ms. Stacey N. Harris
Rates Analyst
Rocky Mountain Region
Western Area Power Administration
5555 East Crossroads Boulevard
Loveland, CO 80538-8986
Telephone: (970) 461-7481
e-mail: mtharris@wapa.gov

Ms. Lynn E. Richardson
Rates Analyst
Rocky Mountain Region
Western Area Power Administration
5555 East Crossroads Boulevard
Loveland, CO 80538-8986
Telephone: (970) 461-7440
e-mail: lerichrd@wapa.gov

E-Mail Address for Official Comments

laptransadj@wapa.gov

Materials Posted on Website

http://www.wapa.gov/rm/rm.htm

Table of Contents

I. Introduction

The Western Area Power Administration's (Western) Rocky Mountain Customer Service Region (RMR) is proposing revised rates (Proposed Rates) for the long-term sale of Loveland Area Projects (LAP) transmission and ancillary services. This action is necessary as existing rates expire on March 31, 2004. These Proposed Rates will be applied under existing contracts and Western's Open Access Transmission Service Tariff (Tariff).

RMR will continue to offer network, firm point-to-point, and non-firm point-to-point transmission service to all Transmission Customers. The Proposed Rates will be applicable to existing and future transmission service. As demonstrated in the rate methodology, RMR will be taking transmission service on the same basis as other Transmission Customers. The cost of transmission service for serving RMR's Contract Rates of Delivery will continue to be included in the LAP firm power rate, consistent with existing contracts. These contracts will expire in 2024.

RMR will also offer the following seven ancillary services to all customers:
1) Scheduling, System Control, and Dispatch Service; 2) Reactive Supply and Voltage Control Service from Generation Sources; 3) Regulation and Frequency Response Service; 4) Energy Imbalance Service; 5) Spinning Reserves;
6) Supplemental Reserves; and 7) Transmission Losses Service.

Project Description

RMR delivers Federal power to preference customers in Colorado, Wyoming, Nebraska, and Kansas with hydroelectric power. RMR sells more than 2.3 billion kilowatthours of power. This power is generated at more than 20 hydroelectric plants that are part of Fryingpan-Arkansas (Fry-Ark) Project and the Pick-Sloan Missouri Basin Program-Western Division (P-SMBP-WD) (sold as the Loveland Area Projects) and the Colorado River Storage Project. RMR sells power to utilities across 183 counties.

RMR serves firm electric and transmission customers in a four-state area, over a transmission system of approximately 3,473 miles (5,589 circuit kilometers) and 79 substations. The system includes the 200-MW Virginia Smith AC-DC-AC converter station near Sidney, NE, that transfers power between the eastern and western power grids.

Refer to Appendix C for a map of the RMR transmission system.

<u>P-SMBP-WD</u>

The P-SMBP encompasses a comprehensive program, with the following authorized functions: flood control, navigation improvement, irrigation, municipal and industrial water development, and hydroelectric production for the entire Missouri River Basin.

Multipurpose projects have been developed on the Missouri River and its tributaries in Colorado, Montana, Nebraska, North Dakota, South Dakota, and Wyoming.

The Colorado-Big Thompson (C-BT), Kendrick, and Shoshone Projects were administratively combined with P-SMBP in 1954, followed by the North Platte Project in 1959. These projects are known as the "Integrated Projects" of the P-SMBP. The Riverton Project was reauthorized as a unit of the P-SMBP in 1970. The P-SMBP-WD, including the Integrated Projects, consists of 20 powerplants.

Fry-Ark

Fry-Ark is a transmountain diversion project in central and southeastern Colorado. Fry-Ark diverts water from the Fryingpan River and other tributaries of the Roaring Fork to the Arkansas River on the East Slope of the continental Divide. The Fryingpan and Roaring Fork Rivers are part of the Colorado River Basin, on the west slope of the Rocky Mountains. The water diverted from the west slope, together with regulated Arkansas River water, provides supplemental irrigation, municipal and industrial water supplies, and hydroelectric power production. Flood control, fish and wildlife enhancement, and recreation are other important purposes of Fry-Ark.

Fry-Ark's electrical features consist of the Mount Elbert 206-MW Pumped-Storage Powerplant, the Mount Elbert Switchyard, and the Mount Elbert-Malta 230-kV Transmission Line. In Fiscal Year (FY) 1989, Fry-Ark's Poncha Substation was transferred to the Colorado River Storage Project.

Rates History

Transmission

Prior to August 1, 1982, RMR had a transmission charge of 1.0 mill per kilowatthour (kWh) included in transmission service contracts. The first firm transmission service rate schedule was schedule P-S WD-T1, which became effective on August 1, 1982. This schedule was the first P-SMB-WD transmission rate that included a capacity charge. The rates under this schedule were 1.1 mills per kWh or $9.60 per kilowattyear (kW-year) ($0.80/kilowattmonth (kW-month)). Non-firm transmission service rate schedules using only the energy rate were implemented simultaneously with the firm rates.

On January 1, 1985 Rate Schedule P-S WD-T3 superseded Rate Schedule P-SWD-T1 with a rate of 1.3 mills per kWh or $11.40 per kW-year ($0.95/kW-month).

In 1991, Rate Schedule L-T1 (the first LAP schedule) superseded Rate Schedule P-SWD-T3 at a rate of 2.1 mills per kWh or $18.24 per kW-year ($1.52/kW-month).

On February 1, 1994, Rate Schedule L-T1 was superseded by rate schedules L-T3 and L-T4 at a rate of 2.6 mills per kWh or $22.52/kW-year ($1.88/kW-month).

On April 1, 1998, Western implemented its Tariff and at that time rate schedules L-T3 and L-T4 were superseded by rate schedules L-FPT1 and L-NFPT1, and L-NT1. The current rate for L-FPT1 is $2.88/kW-month. The current rate for L-NFPT1 is 3.75 mills per kWh or $34.57/kW-year. The current annual revenue requirement for L-NT1 is $40,570,808. All of these rates became effective October 1, 2002, and are updated each fiscal year. The formula-based rate schedules will expire on March 31, 2004.

The rates proposed in this document for LAP transmission will supersede the current rates schedules; however, the formula to derive this rate will not change from current methodology.

Ancillary Services

In Order 888, the Federal Energy Regulatory Commission (FERC) identified six ancillary services that must be included in an Open Access Transmission Tariff (OATT). RMR established rates for those six services in April 1998, coincident with the merger of the Western Area Lower Missouri control area (WALM) and a portion of the Western Area Upper Colorado control area (WAUC), into the Western Area Colorado Missouri control area (WACM), which is operated by RMR.

The existing rates have been recalculated each year on October 1st, based on the approved methodologies and an update of financial and customer load data. The rate history for the six ancillary services is as displayed in the following table.

	1998	**1999**	**2000**	**2001**	**2002**	**2003**
Scheduling, System Control, and Dispatch Service 1/	$25.71	$33.72	$34.58	$37.53	$39.06	$43.09
Reactive Supply and Voltage Control Service from Generation Sources 2/	$0.112	$0.108	$0.104	$0.103	$0.101	$0.103
Regulation and Frequency Response Service 3/	$0.147	$0.071	$0.079	$0.104	$0.155	$0.164
Energy Imbalance Service 4/					LAP weighted avg real-time pricing	LAP weighted avg real-time pricing
Operating Reserve Service (Spinning) 5/	Market, plus fee	Market, plus fee	Market, plus fee	Market, plus fee	Market, plus fee	Market, plus fee
Operating Reserve Service (Supplemental) 5/	Market, plus fee	Market, plus fee	Market, plus fee	Market, plus fee	Market, plus fee	Market, plus fee

1/ Charge basis is per schedule per day.
2/ Charge basis is per kilowattmonth.
3/ Charge basis is per kilowattmonth.
4/ Charge basis is use of LAP weighted average real-time sales and purchase pricing.
5/ Charge is the market cost of the purchase of reserves, plus an amount for administration.

The annual recalculation of the ancillary services rates based on updated financial and load data will continue in these new proposed ancillary services rates. The rates proposed in this document for ancillary services will supersede the existing ancillary rates schedules.

Proposed Schedule

- Informal Customer Meeting took place May 19, 2003
- Public Process
- FRN - Published June 13, 2003
- 90-Day Comment Period closes September 11, 2003
- Information Forums
    - July 14 in Denver, CO, at 9 a.m. MDT
    - July 15 in Lincoln, NE, at 1 p.m. CDT
- Comment Forum
    - August 6 in Denver, CO, at 11 a.m. MDT
- Address Comments
- Record of Decision mid-November 2003
- Rate Announcement December 2003
- Implement Rate - January 1, 2004

II. Proposed Rates for LAP Transmission Service

RMR offers Network Integration (Network) and Point-to-Point transmission services. These services include the transmission of energy to points of delivery on the LAP interconnected high-voltage system, which includes transmission lines, substations, communication equipment, and related facilities. Transmission service for RMR's Federal customers will continue to be bundled in their firm electric service rate. The transmission rates include the cost of one ancillary service, Scheduling, System Control, and Dispatch Service.

The methodology used for rate development and billing purposes and the implementation process are described below and detailed in Appendix A.

The current LAP transmission rate is \$2.88/kW-month for Firm Point-to-Point Transmission Service and 3.75 mills/kWh for Non-Firm Point-to-Point Transmission Service, as outlined in Rate Schedules L-FPT1 and L-NFPT1. The current annual revenue requirement for L-NT1 is \$40,570,808. These rate schedules, effective on October 1, 2002, are formula rate schedules and are updated every fiscal year to reflect current financial and load data.

The charge for Network is based on the transmission customer's monthly load-ratio share of the annual revenue requirement for transmission. Firm and Non-Firm Point-to-Point Transmission Service are based on reserved capacity on the transmission system.

The formula for calculation of rates for transmission services will remain unchanged and are as follows:

Network Transmission Service:	Load-ratio share of one-twelfth of the annual revenue requirement for transmission of \$38,776,237.
Firm Point-to-Point Transmission Service:	\$2.68/kW-month
Non-Firm Point-to-Point Transmission Service:	Maximum of 3.75 mills/kWh

These rates will take effect on October 1, 2003, under Western's existing approved rate formula, and will remain in effect when the proposed formula rate is placed into effect on January 1, 2004. If the formula rate is approved by FERC, it will remain in effect through December 31, 2008.

Annual Transmission Revenue Requirement

The Annual Transmission Revenue Requirement is applicable to both Network and Point-to-Point transmission services. The Annual Transmission Revenue Requirement is the Annual Transmission Cost, adjusted for revenue credits and costs associated with expenses which expand the capacity available for transmission. The formula is:

A		B		C		D		E
Annual Transmission Revenue Requirement	=	Annual Transmission Cost	+	Transmission Expenses Increasing Transmission System Capacity	-	Estimated Non-Firm Point-to-Point Transmission Service	-	Revenue Credit For Existing Contracts

This formula applied to the 2002 data is:

A		B		C		D		E
$38,776,237	=	$45,276,458	+	$500,000	-	$2,510,181	-	$4,490,040

The Transmission Expenses Increasing Transmission System Capacity is the estimated amount RMR will be crediting for augmentation of the LAP Transmission System.

The Non-Firm Point-to-Point Transmission Service is the actual non-firm sales made by RMR on the LAP transmission system during FY 2002.

The Revenue Credit for Existing Transmission Contracts includes a revenue credit for transmission revenue received from Scheduling, System Control and Dispatch as well as from Short-Term Firm Point-to-Point transmission contracts.

The Annual Transmission Cost is the result of the Annual Fixed Charge Rate applied to the Net Investment Cost for Transmission Facilities. The formula is:

Annual Transmission Cost = Annual Fixed Charge Rate x Net Investment Cost for Transmission Facilities

This formula applied to FY 2002 data is:

$45,276,458 = 19.812% x $228,530,479

The Net Investment Cost for Transmission Facilities was determined by an analysis of the LAP transmission system. All costs of Fry-Ark were considered generation-related and, therefore, excluded from the transmission revenue requirement. Each LAP facility was identified by function: transmission, sub-transmission, distribution, or generation-related. Only the investment costs of the facilities identified as 'transmission' were used in developing the proposed transmission rates. The investment costs of facilities identified as 'sub-transmission' and 'distribution' were allocated to RMR's federal customers as the RMR's sub-transmission system is used primarily for delivery of Federal power to RMR's Federal customers. If a transmission customer requires the use of RMR's sub-transmission system, an additional facility-use charge is assessed.

The total investment costs for facilities performing the function of transmission include all transmission lines that are normally operated in a continuously-looped manner, and the associated substations and switchyard facilities. For the LAP transmission system, these are primarily the 115-kV and 230-kV transmission lines. In addition, a portion of the communication and maintenance facilities were included in the investment costs for transmission. The total investment cost for transmission facilities, as of September 30, 2002, is \$340,028,550. The allowance for depreciation on these facilities is \$111,498,071, yielding a net investment cost of \$228,530,479.

The Annual Fixed Charge Rate includes operation and maintenance expenses, administrative and general expenses, depreciation expense, and interest expense. The formula is:

$$\overset{\textbf{A}}{\text{Annual Fixed Charge Rate}} = \frac{\overset{\textbf{B}}{\text{Annual Operation \& Maintenance Expenses}} + \overset{\textbf{C}}{\text{Annual Administrative \& General Expenses}} + \overset{\textbf{D}}{\text{Annual Depreciation Expenses}}}{\text{Net Investment}} + \frac{\overset{\textbf{E}}{\text{Annual Interest Expenses}}}{\text{Unpaid Balances}}$$

The formula applied to the FY 2002 data is:

A		**B**		**C**		**D**		**E**
19.812%	=	7.070%	+	1.732%	+	3.371%	+	7.639%

The source for annual operation and maintenance expenses, annual administrative and general expenses, annual depreciation expenses and annual interest expenses is the Results of Operations for the Rocky Mountain Customer Service Region - Pick-Sloan Missouri Basin. The source for unpaid balance is the amount reported to the Historical Financial Data in Support of the Power Repayment Study for the Pick-Sloan Missouri Basin Program.

Appendix A illustrates the detailed calculation of the revenue requirement, based upon FY 2002 financial data.

Transmission System Load

The LAP transmission System Total Load is the average monthly system peak for network use (including Federal load), plus the reserved capacity for all firm point-to-point use.

The LAP Transmission System Total Load is calculated as follows, based upon FY 2002 data:

Federal Load	604,640	
Network Transmission Customers	522,496	
Subtotal Network Load	1,127,136	kW
Point-to-Point Reserved Capacity	79,635	
LAP Transmission System Total Load	1,206,771	kW

This load was derived as follows:

- Obtained hourly individual revenue meter readings for network delivery points on the LAP transmission system and the sum of the hourly meter reading to find the LAP system peak.
- Added the Federal power customers that do not receive LAP auxillary transmission.
- Added the reserved capacity for point-to-point customers to determine the LAP Transmission System Total Load.

Network Transmission Service

The monthly charge for Network is the product of the transmission customer's load-ratio share times one-twelfth of the Annual Transmission Revenue Requirement. The customer's load-ratio share is the ratio of their network load to the LAP Transmission System Total Load, which will be calculated on a rolling 12-month basis (12 coincident peak average or 12-CP).

The customer's load-ratio share will be derived as follows:

- Identify the LAP transmission system peak hour for the month.
- Calculate the total delivery to each individual Network Transmission service customer for the monthly peak hour.
- Identify the part of the total delivery associated with each customer's monthly LAP entitlement.
- Identify the network delivery during each of the 12 monthly peaks (total delivery less monthly Federal entitlements).
- Sum the 12 monthly peaks and divide by 12 months to derive the 12-CP for each Network Transmission Customer.

- The 12-CP is applied to the system peak to derive the transmission customer's ratio share of the monthly revenue requirement.

Appendix A illustrates the estimated customer load-ratio share and the breakdown of the total transmission system 12-CP.

Firm Point-to-Point Transmission Service

The proposed rate for firm point-to-point transmission service is the Annual Transmission Revenue Requirement, divided by the LAP Transmission System Total Load.

The formula for the rate is as follows:

$$\text{Firm Point-to-Point Transmission Rate} = \frac{\text{Annual Transmission Revenue Requirement}}{\text{LAP Transmission System Total Load}}$$

The rate based on FY 2002 financial and load data is:

Yearly Delivery: $32.13/kW of reserved capacity per year $= \frac{\$38,776,237}{1,206,771 \text{ kW}}$

Monthly Delivery:	$2.68/kW of reserved capacity per month
Weekly Delivery:	$0.62/kW of reserved capacity per week
Daily Delivery:	$0.09/kW of reserved capacity per day

Non-Firm Point-to-Point Transmission Service

Non-Firm Point-to-Point Transmission Service is available for periods ranging from 1 hour to 1 month. The rate for Non-Firm Point-to-Point Transmission Service may be discounted based on market conditions, but will never be higher than the Firm Point-to-Point Transmission Service rate, converted to an energy equivalent at 100 percent load factor. The formula for Non-Firm Point-to-Point Transmission Service rate is:

$$\text{Maximum Non-Firm Point-to-Point Transmission Rate} = \text{Firm Point-to-Point Transmission Rate}$$

Based on the proposed Firm Point-to-Point Transmission Service Rate, the maximum Non-Firm Point-to-Point Transmission Service Rate is:

Monthly Delivery:	$2.68/kW of reserved capacity per month
Weekly Delivery:	$0.62/kW of reserved capacity per week
Daily Delivery:	$0.09/kW of reserved capacity per day
Hourly Delivery:	3.75 mills/kWh

Unauthorized Use of Transmission

In the event that a transmission customer (including the transmission provider for third-party sales) engages in unauthorized use of RMR-managed transmission systems the transmission customer shall be charged 150 percent of the demand charge for the type of service at issue; e.g. hourly, daily, weekly, or monthly, with a maximum demand charge set at monthly.

Unauthorized use is defined as unscheduled or untagged use of the transmission system and any affiliated ancillary service, exceeding reserved capacity at any point of delivery or receipt. Unauthorized use may also include a customer's failure to curtail transmission when requested.

III. Proposed Rates for Ancillary Services

Background

Ancillary Services are necessary to provide basic transmission service, and to correct for the effects associated with undertaking a transmission transaction within a control area.

RMR provides the six FERC-defined ancillary services, subject to availability, as described in this section. The Proposed Rates for these services are designed to recover the costs incurred for providing each of the ancillary services. The Proposed Rates for ancillary services have been, and will continue to be, based on control area investment and expense.

RMR's current ancillary services offerings are: Scheduling, System Control, and Dispatch Service; Reactive Supply and Voltage Control Service from Generation Sources; Regulation and Frequency Response Service; Energy Imbalance Service; Operating Reserves – Spinning Reserve Service; and Operating Reserves - Supplemental Reserve Service. These rates will expire March 31, 2004.

The first two of these rates, Scheduling, System Control, and Dispatch Service and Reactive Supply and Voltage Control Service from Generation Sources are defined by FERC as services that a transmission provider/control area operator <u>must</u> <u>provide</u> and the transmission customer <u>must</u> <u>purchase</u>.

The other four FERC-defined ancillary services: Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserves – Spinning Reserve Service, and Operating Reserves – Supplemental Reserve Service, must be <u>offered</u> by a transmission provider that operates a control area. The transmission customer has the <u>option</u> for these four services to: 1) take the services from the control area operator/transmission provider; 2) self-supply the services for their transaction; or 3) purchase the services from a third-party.

FERC also advised in Order No. 888 that other interconnected operations services may be provided by the transmission provider or third parties to facilitate a particular transmission transaction. In light of this, in FY 2001, RMR identified two additional ancillary services: 1) Unauthorized Use of Transmission and Control Area Resources Service; and 2) Transmission Losses Service. This action was necessary to ensure that financial and/or energy obligations were satisfied for transmission and control area resources and transmission losses, until these services could be offered under Western's Tariff. These rate schedules were both approved by Western's Administrator under authority delegated to the Administrator under Delegation Order No. 00-037.00. These rate schedules are also set to expire on March 31, 2004.

Western is proposing the addition of Transmission Losses Service as an ancillary service in this rate filing. Unauthorized Use of Transmission and Control Area Resources Service will become a component of the transmission rate schedules.

Western is also proposing an additional component to its Regulation and Frequency Response Service rate schedule, in order to offer a separate regulation service for Regulation and Frequency Response Service for Intermittent Renewable Resources.

All of Western's ancillary services and their formula-based rate calculations are presented in Appendix B.

Scheduling, System Control, and Dispatch Service

This ancillary service is one redefined by FERC in Order No. 888-A as a service that can <u>only</u> <u>be</u> <u>offered</u> by the control area operator in which the transmission facilities are located, and <u>must</u> <u>be</u> <u>taken</u> by the transmission customer.

This service is required to schedule the movement of power through, out of, within, or into the transmission provider's transmission system or control area.

The proposed rate for this service will continue to be applied to all transactions submitted by customers who have not purchased transmission as part of that transaction. A customer's purchase of LAP transmission will have the cost of this ancillary service included in that purchase.

While the rate design described below remains consistent with the 1998 rate submittal, the charge basis is changing from "per schedule per day" to "per tag per day". When this rate was first implemented in 1998, the predominant transmission transaction vehicle in the electric utility industry was a "schedule". Schedules were typically communicated with the control area operator from the transmission customer by either telefax machine transmittal and/or telephone call.

In June 2001, WACM implemented a new internal scheduling package, Transmission Intertie Generation Energy Reserves (TIGER). TIGER, integrated with RMR's tagging software package, gave WACM much better management of transmission transactions within WACM.

The new rate schedule incorporates the use of tags in the rate design.

<u>Rate Design</u>

This rate recovers the annual expenses associated with transmission scheduling and tagging, system control, and dispatch service. The revenue requirement is comprised of annual expenses for: 1) personnel, 2) facilities and equipment, 3) Open Access Same Time Information System software, and 4) tagging software. The revenue requirement for FY 2004 is $3,795,998, which represents a reduction of 4 percent from FY 2003's revenue requirement of $3,970,226.

This revenue requirement is then divided by the number of tags per year to derive a rate per tag per day. The number of tags for FY 2002 was 150,537 tags, resulting in a rate of $25.22 per tag per day.

Reactive Supply and Voltage Control Service from Generation Sources

This ancillary service is the other ancillary service that FERC states the transmission provider/control area operator must offer and the transmission customer must purchase from the transmission provider/control area operator.

This service is required to maintain transmission voltages on the transmission provider's/control area operator's transmission system(s)/control area within acceptable limits. Typically, this service is provided from generation facilities under the operational control of the transmission provider/control area operator to produce (or absorb) reactive power within operational limits in order to control voltage. RMR will retain the conditions from the original rate that specify that RMR will waive the charge for this service to those customers with generation in or near the control area, who have agreed to respond to WACM requests for reactive power.

Although all non-owners of generation must take this service, they may reduce the charge for this service to the extent that the customer can reduce its requirement upon the control area for reactive power supply from generation resources.

Rate Design

The rate design for this service is unchanged from the prior filing.

The annualized cost of the Bureau of Reclamation's net generation plant investment is calculated, by use of an annual fixed charge rate methodology. That annual cost is applied to a percentage derived annually that represents WACM generation capacity being utilized for the supply of Reactive Supply and Voltage Control Service from Generation Sources. The result is an annual revenue requirement for this service. The revenue requirement for this service for FY 2004 is $1,798,791, an increase of 9 percent from FY 2003's revenue requirement of $1,644,071.

The annual revenue requirement is then divided by the 12-coincident peak (12-CP) load within WACM that requires Reactive Supply and Voltage Control Service from Generation Sources. The resulting rate is charged to customer's loads in excess of their Contracted Rate of Delivery. The rate for FY 2004 is $0.108/kW-month, an increase of
5 percent from the FY 2003 rate of $0.103/kW-month.

Regulation and Frequency Response Service

This ancillary service requires that the transmission provider/control area operator must offer the service, but the transmission customer has the option to: 1) take the service from the control area operator/transmission provider; 2) self-supply the service for their transaction; or 3) purchase the service from a third-party.

Regulation and Frequency Response Service is necessary for the transmission provider/control area operator to provide for the continuous balancing of hourly scheduled or actual resources, with actual real-time load, as well as for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is provided by the generation facilities under the control of the transmission provider/control area operator that are operated to increase or decrease total generation delivered to the transmission provider's/control area operator's transmission system(s)/control area, predominantly through the use of automatic generating control equipment. In contrast to Energy Imbalance Service outlined below, Regulation and Frequency Response Service corrects for instantaneous variations between the customer's resources and load, even if the variations net to zero over the course of an hour.

RMR undertook an analysis to reevaluate the requirements for the control area's needs for Regulation and Frequency Response Service. WACM, as a control area operating within NERC guidelines and criteria, is subject to fines from Western Electricity Coordinating Council (WECC) for noncompliance with Control Performance Standard 1 (CPS1) and Control Performance Standard 2 (CPS2). Generally, CPS1 must have a compliance of 100 percent or greater, and CPS2 must have a compliance of 90 percent or greater. Noncompliance with these percentage goals may result in the control area receiving monetary sanctions. This revised analysis done for WACM measured the actual generation changes that occurred to achieve the desired CPS1 and CPS2 levels. The analysis result was that WACM needs 75 megawatts (MW) of regulating capacity per hour in order to be NERC-compliant for this service.

Load-Based Rate for Regulation and Frequency Response Service

The previous update of the rate for this service reflected a need of 67 MW, which was all deemed to have been supplied by LAP and CRSP resources. With the revised analysis' result of a need for 75 MW, LAP's and CRSP's limitations in covering the entire regulating capacity needed to be reexamined.

WACM is a geographically large control area with few resources available with which to balance loads and resources. Therefore, Western has determined that capacity purchases must become a substantial part of the revenue requirement for regulation, and is proposing a mix of Federal resources and non-Federal purchases to provide this capacity. The amount of regulation and cost of these purchases will be revised annually to accurately reflect the capacity needed to supplement hydroelectric resources. The unit cost and revenue requirement for Federal facilities will continue to be calculated each year using the existing methodology's annual fixed charge rate.

This rate will be assessed to customers' auxiliary loads within the control area.

Capacity-Based Regulation and Frequency Response Service

The revised analysis also included the regulating capacity required for intermittent renewable resources located within WACM. At present, RMR estimates that 5 MW of the 75 MW requirement, is the capacity needed to regulate for the existing intermittent renewable resources in WACM. However, RMR recognizes that Regulation and Frequency Response Service for these generating units differs from the service provided to regulate for load (the 70 MW), in that the intermittent renewable resources are not as predictable as, and can fluctuate to a greater degree than, traditional sources of generation. Therefore, as part of the existing rate for Regulation and Frequency Response Service, RMR has developed a capacity-based charge for regulation of intermittent renewable resources.

This rate is proposed to be assessed to the difference between the customer's schedule and actual output of the unit.

Rate Design

The rate design for this service is proposed to be modified by both: 1) the analysis done to determine capacity required for Regulation and Frequency Response Service; 2) by incorporating a mix of Federal and non-Federal resources to provide the capacity; and 3) expansion of the rate to include a capacity-based rate for intermittent renewable resource regulation service.

Rate Design for Load-Based Regulation

To achieve the 75 MW needed for regulating capacity, RMR assembled the following mix of capacity: 1) a purchase of 30 MW to allow for additional regulating capacity will be made for FY 2004; 2) Twenty (20) MW of capacity is provided by a dynamic signal from the Colorado River Storage Project (CRSP) to WACM; and 3) the remaining 25 MW of regulating capacity required is priced as a LAP resource, using the annual fixed charge rate methodology to determine an annual revenue requirement, divided by the nameplate capacity of the LAP regulating units.

The total revenue requirement proposed for the rate to be implemented in January 2004, is $5,031,873, an increase of 35 percent over FY 2003's revenue requirement of $3,727,782. However, the rate for this service is only increasing 13 percent, from $0.164/kW-month to $0.185/kW-month, due to a significant increase in the load requiring regulation.

Rate Design for Capacity-Based Regulation

The rate design for this service utilizes the same revenue requirement as the load-based rate and the same 75 MWs for regulating capacity. However, the rate is derived based on the capacity instead of load, ($5,031,873 / 75,000), and is calculated to be $5.59 per kW-month.

An analysis done by Western to measure the moment-to-moment variation of intermittent renewable resources within WACM indicates that 27 percent of the nameplate capacity of those units is required for regulation. Western is proposing using the 27 percent (+/- 13.5 percent) as a bandwidth for measurement of service actually taken.

Western plans to offer resource owners a credit for more closely matching generation schedules with actual output. Also, Western is proposing additional charges for resource owners utilizing more than the 27 percent of nameplate capacity.

The proposed calculation of charges and credits for this service will begin with 27 percent of the nameplate capacity for the unit; e.g., for a 6-MW capacity unit, the regulation estimated to be taken would be 1.6 MW (+/- .8 MW). If after-the-fact actual data revealed that the maximum usage was only .3 MW, a credit of .5 MW would be given. If, however, the after-the-fact actual data revealed that the maximum usage was 1.2 MW, the customer would be charged for the .8 MW, plus an additional .4 MW.

Energy Imbalance Service

This ancillary service also requires that the transmission provider/control area operator must offer the service, but the transmission customer has the option to: 1) take the service from the control area operator/transmission provider; 2) self-supply the service for their transaction; or 3) purchase the service from a third-party.

Energy Imbalance Service was designed and implemented to encourage transmission customers and others serving load within the control area to match resources and loads within each hour. This service effectively balances any net mismatch over an hour between the scheduled or actual delivery of energy and the actual load being served in the control area.

Rate Design

Changes

The rate design for this service is changing slightly. The changes are: 1) expansion of the 2 MW minimum deviation to 4 MW minimum deviation; 2) for service provided outside the bandwidth, a reduction of the penalty from 50 percent to 25 percent; 3) rounding of the final hourly energy imbalance service taken for the purposes of pricing; and 4) treatment of jointly owned generators' imbalances.

1. The minimum deviation of 2 MW allowed entities with loads less than 40 MW to have a wider bandwidth than +/- 5 percent. The expansion of this minimum deviation to 4 MW will provide more tolerance for small customers who operate without the benefit of 24-hour dispatching capability.

2. The penalty for out-of-bandwidth excursions will be reduced from 50 percent to 25 percent. Out-of-bandwidth excursions will continue to be priced according to whether or not the customer under or over delivered. These excursions will be charged 125 percent of the purchase price for under delivery, and credited 75 percent of the sale price for over delivery.

3. Energy Imbalance Service hourly calculations will be rounded to whole MWs to more accurately align a customer's ability to schedule only in MWhs, with the final result of the customer's Energy Imbalance Service. RMR anticipates that the impact for this change will be negligible, as the rounding of final calculations should be offsetting, except in the case of static non-diverse loads.

4. For jointly owned generators, the charges and/or credits for Energy Imbalance Service will be assigned to the operating agent of the generator, unless WACM is provided with a legally binding signed agreement from the owners designating a specific methodology to allocate among owners and entitlees. The bandwidth established for generator imbalance shall be +/- 2 percent of the actual hourly generation of the units at issue. The Energy Imbalance Service charges and credits shall be in accordance with the terms and conditions of Western's Rate Schedule L-AS4.

<u>Components Unchanged</u>

1. The bandwidth of +/- 5 percent will remain; as will the financial settlement for all Energy Imbalance Service.

2. The pricing used, the LAP weighted average real-time sale or purchase pricing will also remain as part of the new rate. The defaults for this pricing when no hourly sale or purchase has been made for both within and outside the bandwidth are:

   1. LAP weighted average real-time sale or purchase pricing for the day (on and off peak).
   2. LAP weighted average real-time sale or purchase pricing for the month (on and off peak).
   3. LAP weighted average real-time sale or purchase pricing for the prior month (on and off peak).

4. LAP weighted average real time sale or purchase pricing for the month prior to the prior month (and continuing until sale or purchase pricing occurs) (on and off peak).

Expansion of the bandwidth will be done to accommodate: 1) physical resource loss; 2) contributions for frequency bias; 3) transition of large thermal resources; and 4) energy imbalance service for intermittent renewable resources. Details are as follows:

1. Western will expand the bandwidth to accommodate the amount of time required for an emergency response (2 hours) due to an uncontrollable event, and made by a Western-recognized reserve-sharing group, such as the Rocky Mountain Reserves Group. A response made by a member of the reserve group will be accounted for by an after-the-fact schedule. Therefore, no expansion will be necessary for the entity receiving the response. The expanded bandwidth will apply for the responder in this instance.

2. For those entities operating generation in a tie-line bias mode, subject to the requirements for Frequency Responsive Reserves (FRR), Western intends to offset the calculated raw energy imbalance by an amount equal to the weighted average hourly frequency multiplied by the entity's frequency response bias factor. This will eliminate any Energy Imbalance Service costs incurred due to provision of frequency support to the interconnection. For an entity to qualify for this accommodation, the requesting entity must provide Western with data required for physical confirmation of FRR participation. No credit will be allowed for frequency bias contributions until the requested real-time and engineering data is provided to WACM.

3. During transition of large base-load thermal resources between on-line and off-line, Western will expand the bandwidth until the unit is adjusted to its desired position: on or off line. Expanded bandwidth will be applied hourly beginning with the hour in which the unit generates less than the minimum scheduling level. Forced transitions from on-line to off-line will receive expansion of the bandwidth as explained in the physical resource loss clause. Bandwidth will not be expanded when ramping services have been acquired by another entity.

4. Energy Imbalance Service taken by intermittent renewable resources will have no bandwidth applicable to the taking of that service. This will assure that intermittent renewable resources only pay for their impact on the system and will not be penalized for out-of-bandwidth excursions.

<u>Control Area Operating Constraints</u>

WACM will reserve the right to offer no credit for Energy Imbalance Service over deliveries during times of WACM operating constraints; such as "must-run" hydrologic conditions, or when WACM cannot dispose of surplus energy. Due to the unpredictable nature of hour-to-hour energy imbalance and the very short notice for disposition of over deliveries, Western expects some hours of zero value sales and the elimination of credits. If Western is unable to dispose of the entire net over delivery and operating criteria for the control area are not met, there may be financial sanctions to Western from reliability oversight agencies, such as NERC and WECC. In these cases, credit to customers will be eliminated and parties over delivering may share in the cost to Western of the sanction. Also, customers who under deliver may share in any sanctions brought to Western by reliability oversight agencies.

Control Area Aggregate and Pricing

For imbalances within the bandwidth, the gross Energy Imbalance Service taken for all applicable entities within WACM shall be netted to determine an aggregate energy condition for WACM.

In times when the control area aggregate is surplus, all within-band energy imbalances, whether they be over or under delivered, will be assessed or credited the LAP average real-time sale price for that hour. In times when the control area aggregate is deficit, all within-band energy imbalances, whether they are over or under delivered, will be assessed or credited the LAP average real-time purchase price.

Within-the-Bandwidth Pricing of Energy Imbalance Service

Within the bandwidth, the energy imbalance for each applicable entity within WACM shall be totaled and netted to determine a control area aggregate energy condition for WACM. The sign of the aggregate energy condition for WACM will determine whether sale or purchase pricing will be used (surplus hours will use sale pricing, and deficit hours will use purchase pricing). For all within-band excursions, 100 percent of the LAP real-time average sale or purchase price for any hour will be charged or credited to the customers.

Outside-the-Bandwidth Pricing of Energy Imbalance Service

Outside the bandwidth, entities' excursions will not be priced as to WACM's energy aggregate energy condition, but will stand alone and be priced as to whether the excursion was an under or over delivery. The penalty for this out-of-bandwidth excursion will be a charge of 125 percent of the average purchase price if the excursion was an under delivery, and will be a credit of 75 percent of the average sale price if the excursion was an over delivery.

Operating Reserves – Spinning and Supplemental Reserves Service

This proposed rate is unchanged.

This ancillary service requires that the transmission provider/control area operator must offer the service, but the transmission customer has the option to: 1) take the services from the control area operator/transmission provider; 2) self-supply the services for their transaction; or 3) purchase the services from a third-party.

Western is only able to meet its own internal requirements for reserves, and has no long-term reserves available for sale. At a customer's request, Western will purchase and pass through the cost of reserves, plus any activation energy, plus a fee for administration. For all reserves purchased, the customer will be responsible for purchasing adequate transmission to support the purchase.

Transmission Losses Service

This ancillary service is currently offered, but being proposed to be brought under Western's Tariff. This is a service that will be offered by the transmission provider/control area operator and that the transmission customer has the option to: 1) take the service from the control area operator/transmission provider; 2) self-supply the service for their transaction; or 3) purchase the service from a third-party.

In sections 15.7 and 28.5 of its Tariff, Western provided for the assessment of losses on all transmission transactions and stated that the specific loss factors are to be set forth in each service agreement.

In FY 2001 RMR began experiencing numerous transmission transactions that were deficient of loss energy obligation. By default WACM, as the control area operator, was placed in the position of purchasing expensive spot-market energy to cover transmission customers' uncompensated loss energy. Additionally, Western found that some transmission customers prefer, in lieu of scheduling loss energy, to provide financial settlement for their transmission loss obligations under RMR's Tariff.

Therefore, Western implemented Rate Schedule L-LO1, Transmission Losses Service, which offers customers the option of either supplying the appropriate loss energy (calculated currently to be 5 percent of the transaction), or to settle the obligation financially. If they opt for financial settlement, this service sets forth the terms and conditions for doing so.

This rate schedule was approved in FY 2001 by Western's Administrator. The rate expires on March 31, 2004, and is being proposed for transition into Western's ancillary service portfolio.

The charge is currently assessed to Non-Firm and Firm Point-to-Point Transmission Service customers, for all prescheduled and real-time transmission transactions that utilize RMR-managed transmission facilities. For energy settlement, customers doing prescheduled transactions must supply concurrent loss energy. For customers engaged in real-time transactions, RMR allows a 7-day lag for the energy return, which must follow the same load profile as the original real-time transaction. In the event that energy is not settled in one of these ways, the transmission customer's loss energy obligation will be settled financially.

In the case of Network Transmission Service customers, transmission and transformer losses applicable under customers' respective contracts or service agreements are calculated as part of the customers' Energy Imbalance Service.

There are no significant changes are proposed for this service. The only modification will be a pricing change to calculate the cost of the loss energy. Currently, the pricing used for this valuation is Palo-Verde on- and off- peak daily pricing. Western proposes changing to LAP average real-time purchase prices, with the same pricing defaults as exist in the Energy Imbalance Service rate.

IV. Rate Adjustment Procedure

The formal Public Consultation and Comment Period will begin with the publication of the Federal Register Notice, and will end not less than 90 days later. During this time, interested parties may consult with and obtain information from RMR representatives about the rate proposals. Two Public Information Forums and one Public Comment Forum will be held during the Public Consultation and Comment Period.

The Public Information Forums will be held:

July 14, 2003 at 9 a.m. MDT
Radisson Stapleton Plaza
3333 Quebec Street
Denver, CO

July 15, 2003 at 1 p.m. CDT
Southeast Community College
1st Floor of the Energy Plaza
11th & O Street
Lincoln, NE

During the Public Information Forum, RMR representatives will explain the need for the Proposed Rate adjustment and answer questions. Questions not answered at the Public Information Forum will be answered in writing at least 15 days before the end of the Consultation and Comment Period. The Public Information Forum will be recorded and transcribed. Copies of the transcript will be available for purchase.

The Public Comment Forum will be held:

August 6, 2003 at 11 a.m. MDT
Radisson Stapleton Plaza
3333 Quebec Street
Denver, CO

At the Public Comment Forum, interested persons may submit written or oral comments. As with the Public Information Forum, the Public Comment Forum will be recorded and transcribed. Copies of the transcript will be available for purchase.

It is requested that individuals planning to speak at either the July or August forums, please notify the RMR Rates Manager, Dan Payton, of their intent to do so at least one week before each meeting so that a speaker list can be prepared.

Written Comments

All interested parties may submit written comments to RMR at any time during the Consultation and Comment Period. All comments must be received by RMR by the end of the comment period. Written comments should be sent to:

Joel K. Bladow
Regional Manager
Western Area Power Administration
Rocky Mountain Customer Service Region
P.O. Box 3700
Loveland, CO 80539-3700

Comments may also be faxed to the Regional Manager at (970) 490-7213 or e-mailed to LAPTransAdj@wapa.gov

For further information, please contact:

Edward F. Hulls
Operations Manager
Western Area Power Administration
Rocky Mountain Customer Service Region
P.O. Box 3700
Loveland, CO 80539-3700

or e-mail to hulls@wapa.gov

Revision of Proposed Rates

After the Consultation and Comment Period has expired and RMR has conducted a thorough review of oral and written comments, RMR may revise the Proposed Rate(s). If Western's Administrator decides that further public comment on the revised Proposed Rate(s) should be invited, a second consultation and comment period may be initiated. In that event, one or more additional meetings will be convened.

Decision on Proposed or Revised Proposed Rates

Following the end of the Consultation and Comment Period(s), Western's Administrator will develop the Proposed Rates. The Deputy Secretary may confirm, approve, and place these rates in effect on a provisional basis. The decision and an explanation of the principal factors leading to the decision will be announced in the Federal Register. RMR proposes to place the rates in effect on January 1, 2004.

Final Decision on the Rate Adjustment

The Deputy Secretary will submit all information concerning the provisional rates to FERC and request approval of the methodologies used in their development, for the period January 1, 2004, through December 31, 2008. FERC may then confirm and approve the submittal, remand it to Western, or disapprove the submittal.

V. Environmental Requirements

Environmental Evaluation

Western will conduct an environmental evaluation of the Proposed Rates and develop the appropriate level of environmental documentation pursuant to the National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4321 *et. seq.*); the Council on Environmental Quality Regulations of implementing NEPA (40 CFR Parts 1500 thorough 1508); and the DOE NEPA Implementing Procedures and Guidelines (10 CFR Part 1021).

Appendix A

WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN REGION
LOADS FOR SYSTEM PEAK
(kW)

SLCA/IP & Auxiliary	**04 Rate 02 Adjusted kW (12cp)**
Cheyenne Light, Fuel and Power	131,736
Flathead Electric	393
Fort Morgan	19,941
Holyoke	2,172
Julesburg	0
MEAN	16,182
PacifiCorp	122,361
Platte River Power Authority	50,148
Torrington	8,763
Tri-State G&T	151,352
Warren Air Force Base	3,181
Willwood L&P	86
WMPA	14,900
Wray	1,281
Subtotal	522,496
Reserved Capacity	
NPPD	9,885
Public Service	69,750
Subtotal	79,635
Federal CROD	604,640
Total Transmission Obligations:	**1,206,771**

WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN CUSTOMER SERVICE REGION
STEP TWO: DETERMINATION OF NET INVESTMENT OF TRANSMISSION FACILITIES

	Total Western Division		Transmission	Subtransmission	Distribution	Generation Related	Eastern Division 3/
% of Total	100.00%		65.37%	21.68%	8.84%	3.07%	1.04%
Investment Cost:							
Total Plant-in-Service 1/	$ 520,122,211		$ 340,028,550	$ 112,765,156	$ 45,970,988	$ 15,973,915	$ 5,383,603
Allowance for Depreciation Balance 2/	$ 170,564,587		$ 111,506,158	$ 36,979,275	$ 15,075,347	$ 5,238,354	$ 1,765,454
Net Investment Cost	$ 349,557,624		$ 228,522,392	$ 75,785,881	$ 30,895,641	$ 10,735,561	$ 3,618,149

1/ P-SMBP-WD facilities only. All Fryingpan-Arkansas facilities are considered generation.

2/ Source: Preliminary FY 2002 Results of Operations, RMR, Pick-Sloan Missouri River Basin, Schedule 4.

3/ The investment costs for a bay at Yellowtail Switchyard (25% of Switchyard costs), Stegall-Wayside, and New Underwood-Stegall, and eastern side of Stegall Substation appear in the Financial Records of the P-S Missouri Basin Program, Western Division. These facilities serve loads in the P-S Missouri Basin Program, Eastern Division (P-SMBP, ED), and are therefore included in the transmission revenue requirement for P-SMBP, ED.

WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN CUSTOMER SERVICE REGION
DETERMINATION OF LOVELAND AREA PROJECTS ANNUAL FIXED CHARGE RATE FOR TRANSMISSION

Line No.	Description	Units	Amount	Notes
1	A. Operation and Maintenance Expense			
2	Transmission O&M Expense	$	24,713,773	Source: FY 2002 Preliminary Results of Operations, RMR, P-SMBP, Schedule 11
3				
4	Net Investment Cost	$	349,557,624	From Step 2
5				
6	O&M as a % of Net Investment Cost	%	7.070%	L2/L4
7				
8	B. A&G Expense			
9	Transmission A&G Expense	$	6,054,929	Source: FY 2002 Preliminary Results of Operations, RMR, P-SMBP, Schedule 11a
10				
11	Net Investment Cost	$	349,557,624	From Step 2
12				
13	A&G as a % of Net Investment Cost	%	1.732%	L9/L11
14				
15	C. Depreciation Expense			
16	Transmission Depreciation Expense	$	11,784,450	Source: FY 2002 Preliminary Results of Operations, RMR, P-SMBP, Schedule 4
17				
18	Net Investment Cost	$	349,557,624	From Step 2
19				
20	Depreciation as a % of Net Investment Cost		3.371%	L16/L18
21				
22				
23	D. Taxes Other than Income Taxes			
24	Not applicable.			
25				
26	E. General Plant Adder			
27	No General Plant identified at this time, all transmission related.			
28				

WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN CUSTOMER SERVICE REGION
DETERMINATION OF LOVELAND AREA PROJECTS ANNUAL FIXED CHARGE RATE FOR TRANSMISSION

Line No.	Description		Units	Amount	Notes
29	F. Interest				
30	Long Term Debt as of end of FY 01 is:	$270,480,643			Source: FY 2002 Preliminary Results of Operations, RMR, P-SMPB, Schedule 5
31	FY 02 Interest is:	$20,661,791			Source: FY 2002 Preliminary Results of Operations, RMR, P-SMPB, Schedule 5
32	Interest Rate			7.639%	L31/L30
33					
34					
35	G. Annual Fixed Charge Rate				
36	Operation and Maintenance Expense		%	7.070%	
37	A&G Expense		%	1.732%	
38	Depreciation Expense		%	3.371%	
39	Other Taxes		%	0.000%	
40	General Plant Adder		%	0.000%	
41	Interest		%	7.639%	
42	Total			19.812%	

WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN CUSTOMER SERVICE REGION
STEP FOUR: DERIVATION OF ANNUAL TRANSMISSION COST

Net Investment Cost for Transmission: (Step Two)		$228,530,479
	x	
Annual Fixed Charge Rate: (Step Three)		19.812%
Annual Cost for Transmission:		$45,276,458

WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN CUSTOMER SERVICE REGION
STEP FIVE: NETWORK RATE DESIGN
LOVELAND AREA PROJECTS

Annual Cost for Transmission System (See Step Four):

$45,276,458

Transmission Expenses Which Increase Transmission Capacity:

$500,000 1/

1/ Estimate. Tri-State is close to resolution. PRPA has not been resolved yet.

Estimate of Revenue Credits for Non-Firm, Discounted Firm, and Short-Term Point-to-Point; Ancillary Services; and Facility Charges:

($2,510,181)	1/
($180,600)	2/
$0	3/
($289,440)	4/
($804,000)	5/
($1,608,000)	6/
($1,608,000)	7/
($7,000,221)	

1/ Based on FY 2002 actual non-firm transmission revenues.
2/ Revenue from Scheduling, System Control, and Dispatch for FY 2002
3/ Facility Charges for Transmission Facilities.
4/ Short Term, Hayden-Blue River, PSCO, 27 MW x 4 months (June-Sept 2000-2005) (98-RMR-1059).
5/ Short Term, Cargill Power Markets, LLC, 25 MW x 12 month (Oct 2003-Sept 2004)
6/ Short Term, Cargill Power Markets, LLC, 50 MW x 12 month (Oct 2003-Sept 2004) (03-RMR-1364 for Oct 03 thru Mar 04 only)
7/ Short Term , PSCO, 50 MW x 12 month (Oct 2003-Sept 2004) (02-RMR-1340 for Oct 2003 Only)

Calculated Value of Transmission Providers Own Use of Transmission System:

$0 Included in Non-Firm Revenue Above

Revenue Adjustments from Existing Contracts that will not be Included in Tariff:

$0

Annual Revenue Requirement for Network Transmission:

$38,776,237

WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN CUSTOMER SERVICE REGION
STEP SIX: FIRM POINT-TO-POINT RATE DESIGN
LOVELAND AREA PROJECTS

Annual Revenue Requirement:

$38,776,237

Transmission System Load (See Step One):

1,206,771 kW

Firm Point-to-Point Transmission Rate in $/kW:

$32.13	**/kW-year**
$2.68	**/kW-month**
$0.62	**/kW-week**
$0.09	**/kW-day**

WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN CUSTOMER SERVICE REGION
STEP SEVEN: NON-FIRM POINT-TO-POINT RATE DESIGN
LOVELAND AREA PROJECTS

Firm Point-to-Point Rate in $/kW-day:

$0.09 /kW-day

Non-Firm Point-to-Point Transmission Rate:

3.75 Mills/kWh 1/

1/ $/kW-day divided by 24 Hours/day multiplied by 1000.

Appendix B

January 2004
Scheduling, System Control, and Dispatch Service Rate

A. Scheduling and Dispatch 2002 Salary Costs	$	3,476,577	
B. Annualized PMOC Costs	$	271,422	
C. OASIS/OATI Costs (FY 02 Expenses)	$	167,999	
D. Total Revenue Requirement	**$**	**3,915,998**	(A + B + C)
E. Revenue Credit (OASIS/tagging revenues)	**$**	**(120,000)**	
F. Total Revenue Requirement	**$**	**3,795,998**	(D + E)
G. FY 2002 Estimated Number of Annual Daily Tags		150,537	
H. Rate for Scheduling and Dispatch Service ($/schedule/day)	**$**	**25.22**	(F / G)

Annual Fixed Charge Rate
for Generation
(based on Bureau of Reclamation investment/costs and a portion of generation-related from Western)

Line No.		Item		Amount	Source		Value	
1		**A. Operation and Maintenance for Generation**						
2		Generation O&M Expense				$	27,995,719	1/
3		Generation of Electricity by Others						
4		Total O&M Expense for Generation				$	27,995,719	
5								
6		Net Generation Plant Investment				$	357,435,236	2/
7								
8		O&M, as a Percent of Net Generation Plant Investment					**7.832%**	Line 2 / Line 6
9								
10	1/	Pick-Sloan (BOR)	$	23,385,622	(Source: FY 02 FS, Schedule 16, O&M to Power)			
11		Fry-Ark (BOR)	$	3,665,498	(Source: FY 02 FS, Schedule 16, O&M to Power)			
12		Pick-Sloan Transmission O&M (Western)	$	758,713	(FY 02 Transmission O&M Costs Allocated to Generation)			
13		Pick-Sloan A&G (Western)	$	185,886	(FY 02 Transmission O&M Costs Allocated to Generation)			
14	2/	Net Transmission Costs Allocated to Generation	$	10,736,259	(FY 02 Net Transmission Investment Allocated to Generation)			
		Pick-Sloan Net Generation Plant Investment	$	234,728,574	(Source: FY 02 HFD, Draft Schedule 17, less accumulated depreciation)			
		Fry-Ark Net Generation Plant Investment	$	111,970,403	(Source: FY 02 Fry-Ark FS and FY 02 PRS, less accumulated depreciation)			
15								
16		**B. A&G Expense for Generation**						
17								
18		Generation A&G Expense				$	185,886.00	1/
19								
20		Net Generation Plant Investment				$	357,435,236	
21								
22		A&G, as a Percent of Net Generation Plant Investment					**0.052%**	
23								
24								
25	1/	These costs are not separable in Bureau data; included in O&M, above.						
26								
27		**C. Depreciation Expense for Generation**						
28								
29		Generation Depreciation Expense				$	9,211,882	1/
30								
31		Net Generation Plant Investment				$	357,435,236	
32								
33		Depreciation as a Percent of Net Generation Plant Investment					**2.577%**	Line 32 / Line 34
34								
35	1/	Pick-Sloan (BOR)		$6,807,012	(Source: 02 FS, Schedule 14 for P-SMBP/IP)			
36		Fryingpan-Arkansas (BOR)		$2,043,087	(Source: 02 Fry-Ark FS, Schedule 14)			
37		Pick-Sloan (Western)		$361,783	(FY 02 Transmission Depreciation Costs Allocated to Generation)			

Annual Fixed Charge Rate
for Generation
(based on Bureau of Reclamation investment/costs and a portion of generation-related from Western)

Line

D. Taxes Other than Income Taxes for Generation

38 Not Applicable

41 **E. General Plant Adder**

43 No General Plant Adder identified at this time; all generation related. -

Line		A	B	C	D	F
46		A	B	C	D	F
47			2001	Percentage of Project	Weighted 2002 Interest	Weighted Interest
48	**F. Weighted Interest**	2002 Simple Interest	Unpaid Balances	LTD to Total LTD	Col A / Col B	Col C x Col D
50	Pick-Sloan	$ 8,194,690	$ 64,015,710	30.605%	12.801%	3.918%
51	Fry-Ark	$ 4,247,469	$ 136,764,919	65.386%	3.106%	2.031%
52	Transmission Interest Assigned to Generation	$ 634,317	$ 8,386,113	4.009%	7.564%	0.303%
53			$ 209,166,742	100.000%		6.252%

Line	**G. Annual Fixed Charge Rate**		THIS YEAR		LAST YEAR	DELTA
59	Operation and Maintenance Expense		7.832%		8.819%	-0.987%
60	A&G Expense		0.052%		0.056%	-0.004%
61	Depreciation Expense		2.577%		2.261%	0.316%
62	Other Taxes		-	-		
63	General Plant Adder		-	-		
64	Weighted Interest		6.252%		5.166%	1.086%
66		Annual Fixed Charge Rate	16.713%		16.302%	**0.411% Increase**

October 1, 2003, and January 1, 2004
Reactive Supply and Voltage Control Service from Generation Sources

A.	Annual Fixed Charge Rates			
	Pick-Sloan Missouri Basin Program - WD	16.713%	1/	
B.	Total Net Generation Plant Costs -- Pick Sloan - WD ($)	$308,080,650	2/	(Net Pick-Sloan Investment + Net Fry-Ark Investment + Net No. from Transmission assigned Generation)
C.	Annual Cost of Generation - Pick-Sloan - WD ($)	$ 51,490,478		(A * B)
D.	LAP Capability Used for Reactive Support (%)	2.5%	3/	
E.	Annual Reactive Supply Revenue Requirement	$ 1,689,831	4/	(C * D) + $402,569 for SLCA-IP revenue reqrmt.
F.	Load in Control Area Requiring VAR Support	1,309,284	5/	
G.	Reactive (Gen Source) Charge ($/kW-Yr)	$ 1.291		(E / F)
H.	Reactive (Gen Source) Monthly Delivery ($/kW)	$ 0.108		(G / 12 months)
I.	Weekly Delivery ($/kW)	$ 0.025		(G / 52 weeks)
J.	Daily Delivery ($/kW)	$ 0.004		(I / 7 days)
K.	Reactive (Gen Source) Charge ($/kWh)(100% MLF)	$ 0.000148		((J) / (24 * 1))

1/ Annual Fixed Charge Rate for Generation.
2/ Pick-Sloan Net Investment + Fry-Ark Net Investment + Net Amount Assigned to Generation from Transmission
3/ Derived from WACM power flow simulation study for FY 2002.
4/ Annual Cost of Generation * Capability Used for VAR Support + SLCA-IP's revenue requirement.
5/ 12 Coincidental-Peak Load in WACM requiring VAR Support.

January 1, 2004
Regulation and Frequency Response Service

Calculation of Rate for LAP Units to Provide Regulation

A	FY 2002 Annual Fixed Charge Rate Pick-Sloan Missouri Basin Program - WD		16.713%		
B	FY 2002 Net Regulating Plant Costs -- Pick Sloan ($)	$	237,092,123	1/	
C	Annual Cost Assigned LAP Regulation	$	39,625,945		(A * B)
D	LAP Regulating Plant Nameplate Capacity (kW)		890,000	2/	
E	**LAP Cost/kW ($/kW-Yr)**	**$**	**44.52**		(C / D)
F	**Load in Control Area Requiring Regulation (12-CP in kW)**		**2,270,596**		

Calculation of Regulation and Frequency Response Requirements for WACM

G	**Capacity Required for Regulation and Frequency Response Service (kW)**	**75,000**	**kW**

Calculation of Cost for Regulation and Load Following

H	Contracted Purchase of 30 MW of Capacity (24 hours per day, 365 days per year)	$	9,198,000	(30 MW x $35/MW x 8,760 hours per year)
I	Energy Credit Associated with Contracted Purchase (credited at LAP average sale price of $22/MW for FY 2002	$	(5,781,600)	(30 MW x $22/MW x 8,760 hours per year)
J	Regulating Capacity Provided by CRSP-20 MW	$	502,473	(20 MW - Revenue Requirement Provided to WACM from CRSP)
K	Cost of Providing LAP Capacity for Regulation/Load-Following	$	1,113,088	(25 MW @ $/MW in Line E)
L	Annual Revenue Requirement for Regulation	$	5,031,961	
M	Regulation Charge ($/kW-YR)	$	2.216	(L / F)
N	**Regulation Monthly Delivery ($/kW-Mo)**	**$**	**0.185**	**(M / 12 months)**
O	Regulation Weekly Delivery	$	0.043	(K / 52 weeks)
P	Regulation Daily Delivery	$	0.006	(M / 7 days)
Q	Regulation Hourly Delivery (100% load factor) $/kWh	$	0.000254	((N) / (24 * 1))

January 1, 2004
Regulation and Frequency Response Service

1/ ("Run-of-the-river" powerplants cannot be used to regulate--they are: Buffalo Bill, Shoshone, Spirit Mountain, Heart Mountain, Pilot Butte, Boysen, Alcova, Glendo, Kortes, Guernsey, Big Thompson, Marys Lake, Pole Hill and Green Mountain, Riverton)
Data Source: Schedule 17 - Investment in Commercial Power Facilities for FY 2002 - Detail in tab entitled, "Regulation Net Plant Calculation".

$	47,266,748	Yellowtail Powerplant
$	24,648,251	Glendo (Fremont Canyon used to regulate, which cannot be separated from Glendo Unit)
$	35,758,014	Colorado-Big Thompson Project (Big Thompson/Green Mtn not used, but couldn't separate from C-BT)
$	15,953,395	Kendrick Project (Alcova not used, but couldn't separate in Kendrick)
$	111,972,753	Fryingpan-Arkansas Project
$	1,492,962	Nonspecific Generation Control Facilities
$	237,092,123	Total LAP Investment to Provide Regulation

2/ Loveland Area Projects:

Glendo (P-SMBP)*	38,000	kW
Fremont Canyon (P-SMBP)	66,000	kW
Yellowtail (P-SMBP)	288,000	kW
Kendrick Project*	81,000	kW
Mary's Lake (C-BT)	8,000	kW
Estes (C-BT)	50,000	kW
Pole Hill (C-BT)	33,000	kW
Green Mountain (C-BT)*	26,000	kW
Big Thompson (C-BT)*	5,000	kW
Flatiron (C-BT)	95,000	kW
Mt. Elbert (Fry-Ark)	200,000	kW
LAP Regulating Capacity	890,000	kW

January 1, 2004
Regulation and Frequency Response Service for Intermittent Renewable Resources

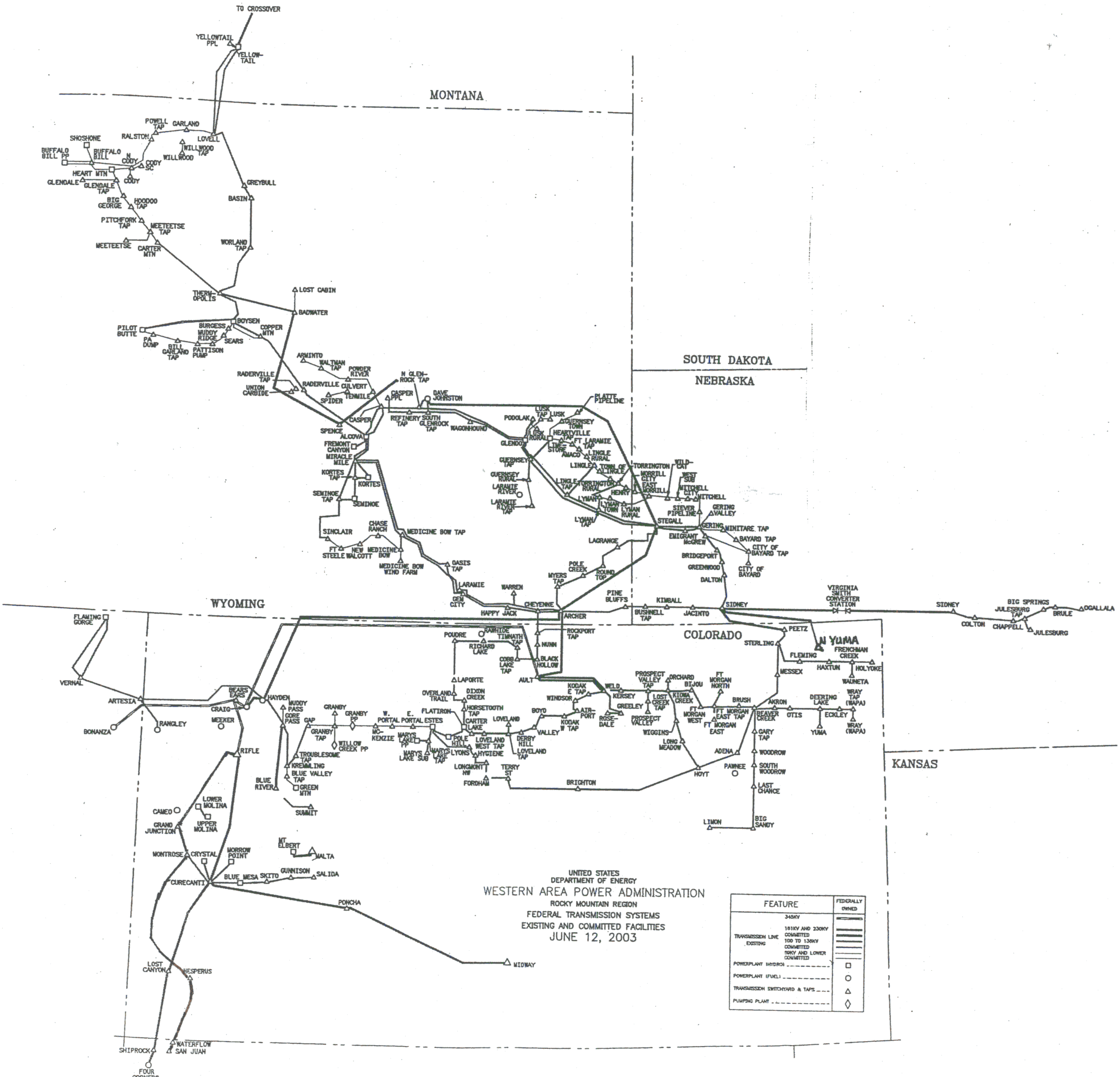
Average of Absolute Deviation From Statistical Mean of
Minute-to-Minute Wind Generation Output within WACM - 27%

* The 27% would be used as a bandwidth measurement (+/- 13.5%)

A	Annual Revenue Requirement for Regulation	$	5,031,961	
B	Capacity Required for Regulation and Frequency Response Service (kW)		75,000	kW
C	Regulation Charge ($/kW-Yr)	$	67.09	(A / B)
D	**Regulation Monthly Delivery ($/kW-Mo)**	$	5.59	(C / 12 months)
E	Regulation Weekly Delivery ($/kW-Wk)	$	1.29	(C / 52 weeks)
F	Regulation Daily Delivery ($/kW-Day		0.18	(E / 7 days)
G	Regulation Hourly Delivery (100% load factor) $/kWh		0.00768	((F / 24)) * 1
H	Price in $/MWh	$	7.68	(H * 1000)

NOTE: Customers actual use of capacity would be analyzed after-the-fact, and an adjustment may be given if the customers' use of capacity at 27% of nameplate did not materialize. Also, if a customer utilized more than 27% of the capacity, additional charge would be made.

Appendix C


UNITED STATES
DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN REGION
FEDERAL TRANSMISSION SYSTEMS
EXISTING AND COMMITTED FACILITIES
JUNE 12, 2003
FEATURE
FEDERALLY OWNED
345KV
TRANSMISSION LINE EXISTING
161KV AND 230KV COMMITTED
100 TO 138KV COMMITTED
69KV AND LOWER COMMITTED
POWERPLANT (HYDRO)
POWERPLANT (FUEL)
TRANSMISSION SWITCHYARD & TAPS
PUMPING PLANT
MONTANA
WYOMING
SOUTH DAKOTA
NEBRASKA
COLORADO
KANSAS
TO CROSSOVER
YELLOWTAIL PPL
YELLOW-TAIL
POWELL TAP
GARLAND
LOVELL
RALSTON
SHOSHONE
BUFFALO BILL PP
BUFFALO BILL
N CODY
CODY SC
CODY
WILLWOOD TAP
WILLWOOD
HEART MTN
GLENDALE
GLENDALE TAP
BIG GEORGE
HOODOO TAP
PITCHFORK TAP
MEETEETSE TAP
MEETEETSE
CARTER MTN
GREYBULL
BASIN
WORLAND TAP
THERM-OPOLIS
LOST CABIN
BADWATER
BOYSEN
PILOT BUTTE
BURGESS
MUDDY RIDGE
COPPER MTN
SEARS
PA DUMP
BILL GARLAND TAP
PATTISON PUMP
ARMINTO
WALTMAN TAP
POWDER RIVER
RADERVILLE TAP
UNION CARBIDE
RADERVILLE
CULVERT
TENMILE
SPIDER
N GLEN-ROCK TAP
CASPER PPL
DAVE JOHNSTON
PLATTE PIPELINE
SPENCE
CASPER
ALCOVA
FREMONT CANYON
MIRACLE MILE
REFINERY TAP
SOUTH GLENROCK TAP
WAGONHOUND
PODOLAK
LUSK TAP
LUSK
LUSK RURAL
GUERNSEY TOWN
HEARTVILLE TAP
FT LARAMIE TAP
GLENDO
LIME STONE
LINGLE RURAL
AMACO
GUERNSEY TAP
GUERNSEY RURAL
LARAMIE RIVER
LARAMIE RIVER TAP
LINGLE
TOWN OF LINGLE
LINGLE TAP
TORRINGTON RURAL
LYMAN
LYMAN TOWN
LYMAN RURAL
HENRY
LYMAN TAP
TORRINGTON
MORRILL CITY
EAST MORRILL
WILD-CAT
WEST SUB
MITCHELL CITY
MITCHELL
SIEVER PIPELINE
GERING VALLEY
STEGALL
GERING
MINITARE TAP
EMIGRANT
McGREW
BAYARD TAP
CITY OF BAYARD TAP
CITY OF BAYARD
BRIDGEPORT
GREENWOOD
DALTON
KORTES TAP
KORTES
SEMINOE TAP
SEMINOE
SINCLAIR
CHASE RANCH
FT STEELE
WALCOTT
NEW MEDICINE BOW
MEDICINE BOW TAP
MEDICINE BOW WIND FARM
OASIS TAP
LARAMIE
GEN CITY
WARREN
HAPPY JACK
CHEYENNE
ARCHER
LAGRANGE
POLE CREEK
ROUND TOP
MYERS TAP
PINE BLUFFS
KIMBALL
BUSHNELL TAP
JACINTO
SIDNEY
VIRGINIA SMITH CONVERTER STATION
COLTON
BIG SPRINGS
JULESBURG TAP
CHAPPELL
BRULE
OGALLALA
JULESBURG
FLAMING GORGE
VERNAL
ARTESIA
BONANZA
RANGLEY
BEARS EARS
CRAIG
HAYDEN
MEEKER
MUDDY PASS
GORE PASS
GAP
GRANBY
GRANBY TAP
GRANBY PP
WILLOW CREEK PP
TROUBLESOME TAP
KREMMLING
BLUE VALLEY TAP
BLUE RIVER
GREEN MTN
SUMMIT
RIFLE
W. PORTAL
E. PORTAL
MC-KENZIE
FLATIRON
ESTES
POUDRE
RAWHIDE
TIMNATH TAP
RICHARD LAKE
COBB LAKE TAP
ROCKPORT TAP
NUNN
BLACK HOLLOW
AULT
LAPORTE
OVERLAND TRAIL
DIXON CREEK
HORSETOOTH TAP
CARTER LAKE
MARYS LAKE PP
MARYS LAKE SUB
MARYS LAKE TAP
POLE HILL
LYONS
LOVELAND WEST TAP
HYGIENE
LOVELAND
LONGMONT NW
FORDHAM
TERRY ST
DERBY HILL
LOVELAND TAP
BOYD
VALLEY
WINDSOR
KODAK E TAP
KODAK W TAP
AIR-PORT
ROSE-DALE
WELD
KERSEY
GREELEY
PROSPECT VALLEY TAP
PROSPECT VALLEY
LOST CREEK TAP
ORCHARD
BIJOU
FT MORGAN NORTH
KIOWA CREEK
FT MORGAN WEST
FT MORGAN EAST TAP
FT MORGAN EAST
WIGGINS
LONG MEADOW
BRUSH
AKRON
OTIS
BEAVER CREEK
GARY TAP
ADENA
WOODROW
SOUTH WOODROW
LAST CHANCE
BIG SANDY
LIMON
PAWNEE
HOYT
BRIGHTON
STERLING
PEETZ
YUMA
FLEMING
FRENCHMAN CREEK
HAXTUN
HOLYOKE
MESSEX
WAUNETA
DEERING LAKE
ECKLEY
WRAY TAP (WAPA)
WRAY (WAPA)
CAMEO
LOWER MOLINA
UPPER MOLINA
GRAND JUNCTION
MONTROSE
CRYSTAL
MORROW POINT
MT ELBERT
MALTA
CURECANTI
BLUE MESA
SKITO
GUNNISON
SALIDA
PONCHA
MIDWAY
LOST CANYON
HESPERUS
SHIPROCK
WATERFLOW
SAN JUAN
FOUR CORNERS

Appendix D

PROPOSED
Rate Schedule L-AS1
Supersedes L-AS1 (4/1/98)
SCHEDULE 1 to Tariff
January 1, 2004

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN REGION
Loveland Area Projects

SCHEDULING, SYSTEM CONTROL, AND DISPATCH SERVICE

Applicable

This service is required to schedule the movement of power through, out of, within, or into the Western Area Colorado Missouri control area (WACM). The charges for Scheduling, System Control, and Dispatch Service are to be based on the rate referred to below. The formula rate used to calculate the charges for service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

The rate will be applied to all electronic tags for WACM non-transmission customers. The Rocky Mountain Region (RMR) will accept any reasonable number of electronic tag adjustments over the course of the day without any additional charge.

The Loveland Area Projects charges for Scheduling, System Control, and Dispatch Service may be modified upon written notice to the customer. Any change to the charges for the Scheduling, System Control, and Dispatch Service shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable service agreement.

The charge for this service shall be assessed to customers with transmission transactions that do not include any segment of Loveland Area Projects (LAP) or Colorado River Storage Project (CRSP) transmission. Customers purchasing LAP or CRSP transmission will have the cost for this service included in that purchase.

Effective

The first day of the first full billing period beginning on or after January 1, 2004, through December 31, 2008.

Formula Rate

$$\text{Cost per Tag} = \frac{\text{Annual Cost of Scheduling and Dispatch Personnel, and Related Costs}}{\text{Number of Tags per Year}}$$

****

Rate

The rate to be in effect January 1, 2004, through September 30, 2004, is $25.22 per tag per day. This rate is based on the above formula and on FY 2002 data.

PROPOSED
Rate Schedule L-AS2
Supersedes L-AS2 (4/1/98)
SCHEDULE 2 to Tariff
January 1, 2004

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN REGION
Loveland Area Projects

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

Applicable

In order to maintain transmission voltages on all transmission facilities within acceptable limits, generation facilities under the control of the Western Area Colorado Missouri control area (WACM) are operated to produce or absorb reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service (VAR Support) must be provided for each transaction on the transmission facilities. The amount of VAR Support that must be supplied with respect to the Customer's (Loveland Area Projects (LAP) Transmission Customers and customers on others' transmission systems within the WACM) transaction will be determined based on the VAR Support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by WACM.

The Customer must purchase this service from the WAC0M operator. The charges for such service will be based upon the rate referred to below.

The formula rate used to calculate the charges for service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

The LAP charges for VAR Support may be modified upon written notice to the Customer. Any change to the charges for VAR Support shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable service agreement. The Rocky Mountain Region shall charge the Customer in accordance with the rate then in effect.

Credit may be given to those Customers with generators in the control area providing WACM with VAR Support. Any crediting arrangements must be documented in the customer's service agreement.

Customers with generation in or near the control area, who agree to provide WACM with reactive supply and voltage control from generation sources when requested, will be granted a waiver from this charge.

Effective

The first day of the first full billing period beginning on or after January 1, 2004, through December 31, 2008.

Formula Rate

$$\text{WACM VAR Support Rate} = \frac{\text{Total Annual Revenue Requirement for Generation} \times \text{Percentage of Resource Capacity Used for VAR Support}}{\text{Load in the Control Area Requiring VAR Support}}$$

****

Rate

The rate to be in effect January 1, 2004, through September 30, 2004, is:

Monthly:	$0.108/kW-month
Weekly:	$0.025/kW-week
Daily:	$0.004/kW-day
Hourly:	$0.000148/kWh

This rate is based on the above formula and on FY 2002 financial and load data.

PROPOSED
Rate Schedule L-AS3
Supersedes L-AS3 (4/1/98)
SCHEDULE 3 to Tariff
January 1, 2004

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN REGION
Loveland Area Projects

REGULATION AND FREQUENCY RESPONSE SERVICE

Applicable

Regulation and Frequency Response Service (Regulation) is necessary to provide for the continuous balancing of resources, generation, and interchange, with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulation is accomplished by committing on-line generation whose output is raised or lowered, predominantly through the use of automatic generating control equipment, as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Western Area Colorado Missouri control area (WACM) operator. The Customer (Loveland Area Projects (LAP) Transmission Customers and customers on others' transmission systems within WACM) must either purchase this service from WACM or make alternative comparable arrangements to satisfy its Regulation obligation. The charges for Regulation are referred to below. The amount of Regulation will be set forth in the service agreement.

The formula rate used to calculate the charges for service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

The LAP charges for Regulation may be modified upon written notice to the Customer. Any change to the Regulation charges shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable service agreement. The Rocky Mountain Region (RMR) shall charge the Customer in accordance with the rate then in effect.

Customers will receive a credit for Regulation on their power bill if they receive Regulation from another source, or self-supply it for their own load. Credit may also be given to those Customers who provide WACM with Regulation. These types of crediting arrangements must be documented in the customer's service agreement.

Effective

The first day of the first full billing period beginning on or after January 1, 2004, through December 31, 2008.

Load-Based Regulation

This service will be offered to cover the instantaneous mismatch between a transmission customer's resources and load. The revenue requirement for this service will be a mix of purchases that provide for regulating capacity and Federal resources. The denominator for this rate will be the load within the control area requiring Regulation and Frequency Response Service.

Load-Based Formula Rate

$$\text{WACM Load Regulation Rate} = \frac{\text{Total Annual Revenue Requirement for Regulation}}{\text{Load in the Control Area Requiring Regulation}}$$

Load-Based Rate

The rate to be in effect January 1, 2004, through September 30, 2004, is:

Monthly: \$0.185/kW-month
Weekly: \$0.043/kW-week
Daily: \$0.006/kW-day
Hourly: \$0.000254/kWh

Capacity-Based Regulation for Intermittent Renewable Resources

This service will be offered to cover the instantaneous mismatch between a customer's scheduled resource and actual output. The revenue requirement for this service will be a mix of purchases that provide for regulating capacity and Federal resources. The denominator for this rate will be the amount of regulating capacity needed within the control area.

Capacity-Based Formula Rate

$$\text{WACM Capacity Regulation Rate} = \frac{\text{Total Annual Revenue Requirement for Regulation}}{\text{Capacity Required to Regulate}}$$

Capacity-Based Rate

The rate to be in effect January 1, 2004, through September 30, 2004, is:

Monthly:	\$5.59/kW-month
Weekly:	\$1.29/kW-week
Daily:	\$0.18/kW-day
Hourly:	\$0.00768/kWh

These rates are based on the above formulae and on FY 2002 financial and load data.

PROPOSED
Rate Schedule L-AS4
Supersedes L-AS4 (7/1/02)
SCHEDULE 4 to Tariff
January 1, 2004

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN REGION
Loveland Area Projects

ENERGY IMBALANCE SERVICE

Available:

Within the Rocky Mountain Customer Service Region=s Western Area Colorado Missouri control area (WACM).

Applicable:
To customers receiving Energy Imbalance Service from WACM.

Effective

The first day of the first full billing period beginning on or after January 1, 2004, through December 31, 2008.

Character and Conditions of Service:

WACM provides Energy Imbalance Service when there is a difference between a customer=s resources and obligations. Energy Imbalance is calculated as resources minus obligations (adjusted for transmission and transformer losses) for any combination of scheduled transfers, transactions, or actual load integrated over each hour. Both Federal transmission customers and customers on others= transmission systems within WACM must either obtain this service from WACM or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation.

Formula Rate for Load Imbalance:

All Energy Imbalance Service provided, both inside and outside the bandwidth, will be settled financially, accounted for hourly at the end of each month. WACM shall establish a deviation band of ± 5 percent (with a minimum of 4 MW) of the actual load to be applied hourly to any energy imbalance that occurs as a result of a customer=s schedules and/or meter data.

Formula Rate for Generator Imbalance:

In the event of a jointly owned generator, Western will assign the energy imbalance for the generator to the operator of the plant, unless provided a signed agreement designating otherwise. All Energy Imbalance Service provided, both inside and outside the bandwidth, will be settled financially, accounted for hourly at the end of each month. WACM shall establish a deviation band of ± 2 percent of the actual generation to be applied hourly to any energy imbalance that occurs as a result of a generator's operation.

Normally, there are four scenarios for Energy Imbalance Service, each of which receive a specific pricing calculation. They are: 1) over delivery within the bandwidth; 2) under delivery within the bandwidth; 3) over delivery outside the bandwidth; and 4) under delivery outside the bandwidth. During periods of control area operating constraints, Western reserves the right to eliminate credits for over deliveries and parties over delivering may share in the cost to Western of the penalty.

Within the Bandwidth

The gross energy imbalance for each applicable entity within WACM shall be totaled and netted to determine an aggregate energy imbalance for WACM. The sign of the aggregate energy imbalance will determine whether sale or purchase pricing will be used (surplus conditions use sale pricing and deficit conditions will use purchase pricing).

Depending upon the sign of the aggregate energy imbalance for all entities within WACM, the pricing for charges and credits within the bandwidth will be:

Weighted Average Sale or Purchase Price @ 100%

Outside the Bandwidth

Each entity within WACM will be charged or credited independently for Energy Imbalance Service taken, dependent upon their over- or under-delivery status.

Under Delivery (customer deficit) = Customer will be charged 125% of the weighted average real-time purchase price

Over Delivery (customer surplus) = Customer will be credited 75% of the weighted average real-time sale price

Expansion of the bandwidth will be allowed during the following instances:

- The loss of a physical resource.
- Upon evidence of proven frequency bias contribution for control area needs.
- The transition (start up/shut down) period for large thermal resources.

Pricing Defaults

When no hourly data is available, the pricing defaults for sales and purchase pricing both within and outside the bandwidth will be applied in the following order:

- Weighted average real-time sale or purchase pricing for the day (on and off peak).

- Weighted average real-time sale or purchase pricing for the month (on and off peak).

- Weighted average real-time sale or purchase pricing for the prior month.

- Weighted average real-time sale or purchase pricing for the month prior to the prior month (and continuing until sale or purchase pricing located) (on and off peak).

Billing

The billing determinants for the above formula rates are specified in the final rate order and in the associated service agreement.

****

Rate

For load imbalance, the bandwidth in effect January 1, 2004, through September 30, 2004, is 10 percent (+/- 5 percent hourly deviation).

For generator imbalance, the bandwidth in effect January 1, 2004, through September 30, 2004, is 4 percent (+/- 2 percent hourly deviation).

PROPOSED
Rate Schedule L-AS5
Supersedes L-AS5 (4/1/98)
SCHEDULE 5 to Tariff
January 1, 2004

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN REGION
Loveland Area Projects

OPERATING RESERVE - SPINNING RESERVE SERVICE

Applicable

Spinning Reserve Service (Reserves) is needed to serve load immediately in the event of a system contingency. Reserves may be provided by generating units that are on-line and loaded at less than maximum output. The Customer (Loveland Area Projects (LAP) Transmission Customers and customers on others' transmission system within Western Area Colorado Missouri control area (WACM)) must either purchase this service from WACM or make alternative comparable arrangements to satisfy its Reserves obligation. The charges for Reserves are referred to below. The amount of Reserves will be set forth in the service agreement.

Effective

The first day of the first full billing period beginning on or after January 1, 2004, through December 31, 2008.

Formula Rate

No long-term Reserves are available beyond internal WACM requirements.

****

Rate

There are no long-term Reserves available from WACM. An offer will be made to purchase Reserves for a Customer and pass through the cost, plus an amount for administration.

The Customer is responsible for providing the transmission to get the Reserves to its destination.

PROPOSED
Rate Schedule L-AS6
Supersedes L-AS6 (4/1/98)
SCHEDULE 6 to Tariff
January 1, 2004

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN REGION
Loveland Area Projects

OPERATING RESERVE - SUPPLEMENTAL RESERVE SERVICE

Applicable

Supplemental Reserve Service (Reserves) is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Reserves may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Customer (Loveland Area Projects' Transmission Customers and customers on others' transmission system within Western Area Colorado Missouri control area (WACM)) must either purchase this service from WACM or make alternative comparable arrangements to satisfy its Reserves obligation. The charges for Reserves are referred to below. The amount of Reserves will be set forth in the service agreement.

Effective

The first day of the first full billing period beginning on or after January 1, 2004, through December 31, 2008.

Formula Rate

No long-term Reserves are available beyond internal WACM requirements.

****

Rate

There are no long-term Reserves available from WACM. An offer will be made to purchase Reserves for a Customer and pass through the cost, plus an amount for administration.

The Customer is responsible for providing the transmission to get the Reserves to its destination.

PROPOSED
Rate Schedule L-AS9
Supersedes L-LO1 (10/8/00)
Sections 15.7 & 28.5 of Tariff
January 1, 2004

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN REGION
Loveland Area Projects

TRANSMISSION LOSSES SERVICE

Applicable

The charge is currently assessed to Transmission Service customers to implement sections 15.7 and 28.5 of Western's Open Access Transmission Tariff, for all prescheduled and real-time transmission transactions that utilize Rocky Mountain Region (RMR)-managed transmission facilities.

Transmission losses are calculated against actual checked-out transactions in the month following the transaction. RMR's transmission loss study percentage rate is applied to each transaction. Losses should be scheduled separately from the associated transaction. Customers may compile loss obligations into one schedule. It is the customers' obligation to curtail or change a loss schedule when the associated transaction changes. The over delivery of transmission losses will result in forfeiture of the energy over delivered. Customers should be able to assess the loss percentage to their daily business and schedule those losses separate from the affiliated transaction.

For energy settlement, customers doing prescheduled transactions must supply concurrent loss energy. For customers engaged in real-time transactions, RMR allows a 7-day lag for the energy return, which must follow the same load profile as the original real-time transaction. In the event that energy is not settled in one of these ways, the transmission customer's loss energy obligation will be settled financially.

In the case of Network Transmission Service customers, transmission and transformer losses applicable under customers' respective contracts or service agreements are calculated as part of the customers' Energy Imbalance Service.

Effective

The first day of the first full billing period beginning on or after January 1, 2004, through December 31, 2008.

Formula Rate

Charges for deficient loss energy obligations will be made hourly, and priced using Loveland Area Projects weighted average real-time purchase prices, with the same defaults as Energy Imbalance Service, plus 10 percent for administration.

****

PROPOSED
Schedule L-FPT1
Supersedes L-FPT1 (4/1/98)
SCHEDULE 7 to Tariff
January 1, 2004

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN REGION
Loveland Area Projects

LONG-TERM FIRM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

Applicable

The Transmission Customer shall compensate Rocky Mountain Region (RMR) each month for Reserved Capacity pursuant to the applicable Firm Point-to-Point Transmission Service Agreement and rates referred to below. The formula rates used to calculate the charges for service under this schedule were promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

RMR may modify the charges for Firm Point-to-Point Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Firm Point-to-Point Transmission Service shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable service agreement. RMR shall charge the Transmission Customer in accordance with the rate then in effect.

Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by RMR must be announced to all Eligible Customers solely by posting on the Open Access Same-Time Information System (OASIS), (2) any Customer-initiated requests for discounts, including requests for use by one's wholesale merchant or an affiliate's use, must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, RMR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Unauthorized Use of Transmission

In the event that a transmission customer (including the transmission provider for third-party sales) engages in unauthorized use of RMR-managed transmission systems the transmission customer shall be charged 150 percent of the demand charge for the type of service at issue; e.g. hourly, daily, weekly, or monthly, with a maximum demand charge set at monthly.

Unauthorized use is defined as unscheduled or untagged use of the transmission system and any affiliated ancillary service, exceeding reserved capacity at any point of delivery or receipt. Unauthorized use may also include a customer's failure to curtail transmission when requested.

Effective

The first day of the first full billing period beginning on or after January 1, 2004, through December 31, 2008.

Formula Rate

$$\text{Firm Point-to-Point Transmission Rate} = \frac{\text{Annual Transmission Revenue Requirement}}{\text{LAP Transmission System Total Load}}$$

If a Transmission Customer requires use of subtransmission facilities, a specific facility use charge will be assessed in addition to this formula rate.

****

Rate

The rate to be in effect January 1, 2004, through September 30, 2004, is as follows.

Maximum of:

Yearly:	$32.13/kW of reserved capacity per year
Monthly:	$ 2.68/kW of reserved capacity per month
Weekly:	$ 0.62/kW of reserved capacity per week
Daily:	$ 0.09/kW of reserved capacity per day

This rate is based on the above formula and FY 2002 data.

PROPOSED
Rate Schedule L-NFPT1
Supersedes L-NFPT1 (4/1/98)
SCHEDULE 8 to Tariff
January 1, 2004

UNITED STATES DEPARTMENT OF ENERGY
WESTERN POWER AREA ADMINISTRATION
ROCKY MOUNTAIN REGION
Loveland Area Projects

NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

Applicable

The Transmission Customer shall compensate Rocky Mountain Region (RMR) for Non-Firm Point-to-Point Transmission Service pursuant to the applicable Non-Firm Point-to-Point Transmission Service Agreement and rate referred to below. The formula rates used to calculate the charges for service under this schedule were promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

RMR may modify the charges for Non-Firm Point-to-Point Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Non-Firm Point-to-Point Transmission Service shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable service agreement. RMR shall charge the Transmission Customer in accordance with the rate then in effect.

Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by RMR must be announced to all Eligible Customers solely by posting on the Open Access Same-Time Information System (OASIS), (2) any Customer-initiated requests for discounts, including requests for use by one's wholesale merchant or an affiliate's use, must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, RMR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Unauthorized Use of Transmission

In the event that a transmission customer (including the transmission provider for third-party sales) engages in unauthorized use of RMR-managed transmission systems the transmission customer shall be charged 150 percent of the demand charge for the type of service at issue; e.g. hourly, daily, weekly, or monthly, with a maximum demand charge set at monthly.

Unauthorized use is defined as unscheduled or untagged use of the transmission system and any affiliated ancillary service, exceeding reserved capacity at any point of delivery or receipt. Unauthorized use may also include a customer's failure to curtail transmission when requested.

Effective

The first day of the first full billing period beginning on or after January 1, 2004, through December 31, 2008.

Formula Rate

Maximum Non-Firm Point-to-Point Transmission Rate	=	Firm Point- to-Point Transmission Rate

****

Rate

The rate to be in effect January 1, 2004, through September 30, 2004, is:

Maximum of:

Monthly:	$2.68/kW of reserved capacity per month
Weekly:	$0.62/kW of reserved capacity per week
Daily:	$0.09/kW of reserved capacity per day
Hourly:	3.75 mills/kWh

This rate is based on the above formula and FY 2002 data.

PROPOSED
Rate Schedule L-NT1
Supersedes L-NT1 (4/1/98)
ATTACHMENT H to Tariff
January 1, 2004

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
ROCKY MOUNTAIN REGION
Loveland Area Projects

ANNUAL TRANSMISSION REVENUE REQUIREMENT FOR NETWORK INTEGRATION TRANSMISSION SERVICE

Applicable

The Transmission Customer shall compensate the Rocky Mountain Region (RMR) each month for Network Transmission Service pursuant to the applicable Network Integration Service Agreement and annual revenue requirement referred to below. The formula for the annual revenue requirement used to calculate the charges for this service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

RMR may modify the charges for Network Integration Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Network Integration Transmission Service shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable service agreement. RMR shall charge the Transmission Customer in accordance with the revenue requirement then in effect.

Unauthorized Use of Transmission

In the event that a transmission customer (including the transmission provider for third-party sales) engages in unauthorized use of RMR-managed transmission systems the transmission customer shall be charged 150 percent of the demand charge for the type of service at issue; e.g. hourly, daily, weekly, or monthly, with a maximum demand charge set at monthly.

Unauthorized use is defined as unscheduled or untagged use of the transmission system and any affiliated ancillary service, exceeding reserved capacity at any point of delivery or receipt. Unauthorized use may also include a customer's failure to curtail transmission when requested.

Effective

The first day of the first full billing period beginning on or after January 1, 2004, through December 31, 2008.

Formula Rate

$$\text{Monthly Charge} = \text{Transmission Customer's Load-Ratio Share} \times \frac{\text{Revenue Requirement}}{12}$$

If a Transmission Customer requires use of subtransmission facilities, a specific facility use charge will be assessed in addition to this formula rate.

If an existing Transmission Customer elects to retain its Transmission Contract and the contract terms are payment on an energy basis, the capacity-unit rate under the formula rate will be converted to an energy-unit rate based on the individual customer's total load factor.

****

Rate

The revenue requirement in effect January 1, 2004, through September 30, 2004, is $38,776,237. This revenue requirement is based on the above formula and FY 2002 data.